CALIFORNIA NATURAL GAS END USE PRICE FORECAST

in support of the 1997 Fuels Report

February 25, 1998

Commissioner Jananne Sharpless and Commissioner Michal C. Moore
Fuels and Transportation Committee
California Energy Commission

in consideration for adoption of the natural gas price forecast
by the full Commission at the
March 18, 1998 Business Meeting
California Energy Commission

Introduction

The California Energy Commission conducts a comprehensive analysis of the California natural gas market every two years by developing a 20 year forecast of market trends, prices and supply availability. This package documents the Fuels and Transportation Committee's proposed forecast of natural gas prices and supplies for each end-use market sector in the state. The Committee recommends adoption of this forecast by the full Commission at the Business Meeting scheduled for March 18, 1998.

The proposed forecast is predicated upon a series of records developed through workshops and hearings held in support of the ***1997 Fuels Report***. This package briefly describes findings from the continental analysis and provides a number of tables and figures describing the end-use price forecast for the residential, commercial, industrial, thermal enhanced oil recovery operations and electricity generation including cogeneration sectors. Forecasts were developed for the major natural gas service territories, namely, Pacific Gas and Electric (PG&E), Southern California Gas Company (SoCal Gas) and the San Diego Gas and Electric Company (SDG&E) regions.

The methodology used to generate the forecast consists of first analyzing the continental market base on resource availability, natural gas transportation capacities and costs and expected demand for natural gas in regional market sectors. Staff utilizes the North American Regional Gas (NARG) model as the principal tool in evaluating the complex and integrated market. California border prices resulting from the first step is then used in generating the end-use prices for each market sector in each natural gas service region within the state.

The following discussion includes: 1) a base case or 'most-likely' projection of regional wellhead production and prices, 2) price and supply availability of natural gas at the California border, and 3) California end-use price estimates by customer class. The first two sections are provided as background information which forms the basis for generating the end-use price forecasts.

While all tables and figures are not included in this package, a complete set can be obtained by calling Mary Freeland at the Energy Commission at (916) 654-4865, or by accessing the Commission's web-site at <**http://www.energy.ca.gov**>.

1. Regional Gas Supply Outlook and Price Trends

Natural gas supplies will remain plentiful for the next several decades. Staff estimates a total resource base (gas recoverable with today's technology) for the Lower 48 of 975 tcf, enough to satisfy current production levels for more than 50 years. This estimate is conservative, given that a significant portion of Canada’s 420 tcf of gas will serve Lower 48 gas markets as well.

Staff expects Lower 48 production to increase from 17.1 tcf in the 1994 base year to 25.9 tcf in 2019 (Table 1). Producers in the Gulf Coast and Rocky Mountain regions will account for most of the increase during the next two decades. Gulf Coast producers, driven by the development of several major deepwater fields in the Gulf of Mexico, will increase production by nearly 60 percent to 14.4 tcf. Rocky Mountain production will almost triple to 3.3 tcf while its share of the Lower 48 market doubles. By the end of the 20-year forecast period, these two regions will account for more than two-thirds of all gas produced in the Lower 48.

TABLE 1
LOWER 48 AND CANADIAN PRODUCTION
(tcf per year)
Base Case

Producing Region	1994	1999	2004	2009	2014	2019
LOWER 48						
Anadarko	2.890	2.435	2.452	2.175	2.172	1.797
Appalachia	0.531	0.679	0.995	1.056	1.273	1.466
California	0.311	0.257	0.341	0.343	0.375	0.388
Gulf Coast	9.135	9.529	10.545	11.732	13.110	14.417
North Central	0.186	0.507	0.611	0.667	0.720	0.763
Northern Great Plains	0.200	0.267	0.302	0.336	0.370	0.452
Pacific Northwest	0.003	0.010	0.019	0.033	0.051	0.082
Permian	1.677	1.727	1.923	1.825	1.588	1.414
Rocky Mountains	1.121	1.693	1.929	2.213	2.634	3.267
San Juan	1.074	1.737	1.998	2.069	2.017	1.882
Total: Lower 48	17.128	18.842	21.116	22.448	24.312	25.927
CANADA						
Alberta	4.033	4.980	5.507	5.971	6.469	6.838
British Columbia	0.569	0.792	0.897	0.831	0.794	0.801
Eastern Canada	0.282	0.000	0.055	0.112	0.149	0.149
Saskatchewan	0.000	0.251	0.159	0.126	0.100	0.104
Total: Canada	4.884	6.023	6.618	7.039	7.487	7.893

In Canada, Alberta producers continue to provide the bulk of Canadian production. With the expected startup of Sable Island production off the Nova Scotia coast, production from Eastern Canada will begin to serve New England markets by 2004. Canadian production for all regions will increase by 1.9 tcf from 1999 to 2019, with about two-thirds of the additional supplies meeting new domestic demand. Canadian exports are projected to rise to 3.9 tcf in 2014 and remain at that level through the end of the forecast period.

A comparison of natural gas prices by region and in the aggregate is shown in Table 2. For the Lower 48, the average price increases from $1.55 per mcf in 1999 to $2.05 per mcf in 2019, representing an annual average increase of 1.4 percent. In Canada, prices increase two percent per year in real terms from $1.10 per mcf in 1999 to $1.65 per mcf by the year 2019.

TABLE 2
LOWER 48 AND CANADIAN WELLHEAD PRICES
(1995 $/mcf)
Base Case

Producing Region	1999	2004	2009	2014	2019
LOWER 48					
Anadarko	1.63	1.82	2.03	2.19	2.36
Appalachia	2.18	2.32	2.51	2.60	2.70
California	1.84	2.01	2.19	2.39	2.58
Gulf Coast	1.58	1.74	1.87	1.98	2.04
North Central	1.80	1.87	1.94	2.01	2.06
Northern Great Plains	1.22	1.27	1.33	1.38	1.43
Pacific Northwest	1.74	1.94	2.10	2.29	2.41
Permian	1.49	1.65	1.84	2.03	2.17
Rocky Mountains	1.33	1.42	1.50	1.57	1.65
San Juan	1.30	1.43	1.57	1.76	1.94
Total: Lower 48	1.55	1.71	1.85	1.97	2.05
CANADA					
Alberta	1.07	1.20	1.31	1.44	1.59
British Columbia	1.11	1.24	1.43	1.60	1.76
Eastern Canada	3.81	2.67	2.51	2.69	2.90
Saskatchewan	1.57	1.85	2.08	2.35	2.57
Total: Canada	1.10	1.23	1.36	1.49	1.65

The growth rate is considerably lower than previous Commission estimates, which have consistently been in the range of 3-4 percent. The sharp decline in the growth is due to two factors: 1) the use of reserve appreciation in the model for the first time, and 2) the change in the owner/producer’s discount rates.

2. Natural Gas Supplies and Prices at the California Border

Four producing regions supply California with natural gas. Three of them (the Southwest US, the Rocky Mountains and Canada) provide approximately 85 percent of all gas to the state. The remainder is produced inside California.

Staff expects adequate supplies to be available from each of the four regions providing gas to California during the forecast period. Supplies available to California are expected to increase from 5.9 bcf/d in the 1994 base year to 7.8 bcf per day by 2019. No significant changes are anticipated in the market shares of supplies from these four supply regions over the forecast horizon. Southwest supplies will continue to dominate the market, holding approximately half of the market. Canadian producers will supply another quarter of the market with the remainder split between Rocky Mountain and California suppliers.

The average California border price is expected to increase by 1.9 percent per year from $1.68 per mcf in 1999 to $2.46 per mcf in the year 2019. Specific estimates of supplies and prices available to California by region are shown in Table 3. The Southwest price represents a weighted average price of gas entering California at Topock or Blythe. Canadian gas is priced at Malin near the Oregon border. Rocky Mountain gas price is set at Wheeler Ridge.

TABLE 3
CALIFORNIA BORDER SUPPLY AVAILABILITY AND PRICE
Base Case

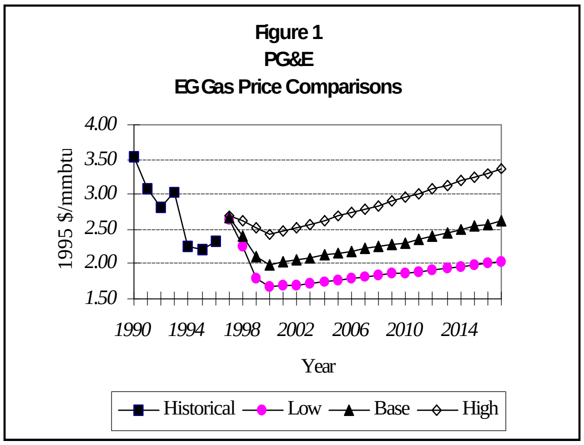
Producing Region	1994	1999	2004	2009	2014	2019
Production (tcf):						
California	0.311	0.257	0.341	0.343	0.375	0.388
Southwest	1.012	1.006	1.169	1.220	1.259	1.319
Rocky Mountains	0.243	0.255	0.290	0.307	0.331	0.353
Canada	0.590	0.544	0.604	0.705	0.767	0.795
Total Supply Available to California	2.156	2.061	2.403	2.574	2.732	2.854
Price (1995$/mcf)						
California	N/A	1.85	2.06	2.28	2.50	2.72
Southwest	N/A	1.69	1.91	2.10	2.32	2.53
Rocky Mountains	N/A	1.76	1.97	2.16	2.37	2.58
Canada	N/A	1.53	1.70	1.85	2.06	2.25
Average Price at California Border	N/A	1.68	1.88	2.05	2.27	2.46

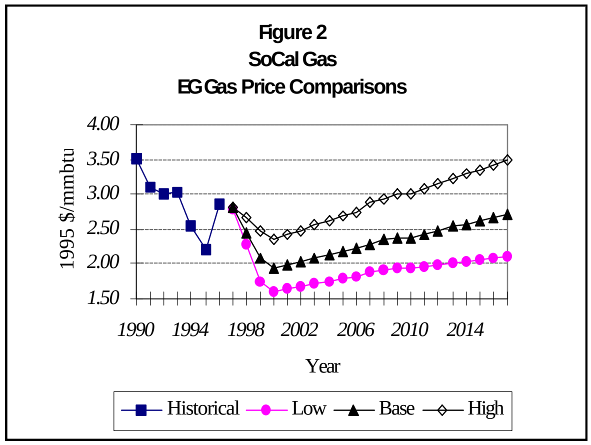
3. End Use Natural Gas Price Forecast

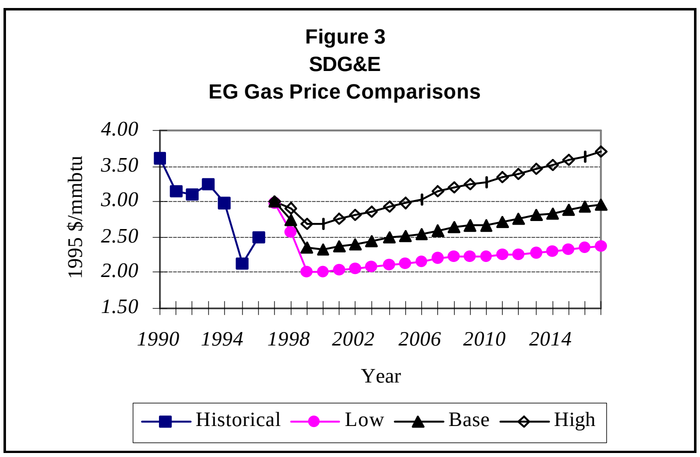
The California border price and supply projections discussed above form the basis for generating the end use price forecasts. The in-state transmission and distribution costs were subsequently derived through an extensive off-line analysis of regulatory issues and rate design criteria. Current regulatory policies, decisions and utility filings were used to determine the share of operational costs allocated by the utility to each market sector. In preparing the forecasts, the California Public utilities Commission's (CPUC) decisions, utility filings and advice letters available at the end of November 1997 were reviewed. The price components derived in this analysis include costs for commodity (natural gas), interstate transportation, intra-state transmission, distribution, and various settlement and regulatory expenses. The components resulting from the analysis were then added together to obtain a natural gas price forecast by sector. All prices are expressed in constant 1995 dollars per thousand cubic feet ($/mcf).

End use price forecasts were prepared for the base case, and two additional cases that represent the upper and lower bounds of expected prices resulting from possible changes in future natural gas markets. Assumptions were derived to simulate the "High" and "Low" price cases based on uncertainties in estimating the total resource availability, technology advances in supply and demand side markets, higher demand (for the high price case) for natural gas resulting from environmental and clean air policies, and lower demand (in the low price case) due to increased efficiency in end use and power generation technologies.

This package includes tables representing the total end use price for each sector in the three major utility service areas. Figures 1, 2 and 3 compare natural gas prices for electricity generation in each service area under the base, high and low price cases. As may be seen from these figures, the high case provides natural gas prices that range from 50 cents per mmBtu higher than the base case in the early years to 75 cent per mmBtu in the later years of the study period. In the early years of the low case, prices are about 40 cents per mmBtu lower than the base case and in the range of 60 cents per mmBtu lower in the later years. The high and low price case forecasts for each market sector have not been included in this package, but are available on request or from the Commission's web-site, as noted earlier.







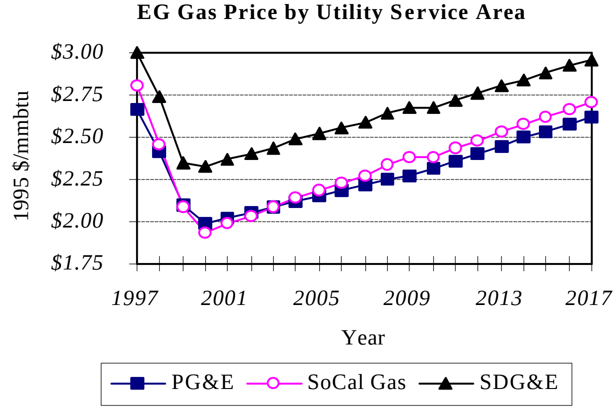
Although price trends over the past few years indicate significant increase in natural gas prices, the current forecast shows that all market sector prices will drop substantially during the next several years (See Tables 4, 5, and 6). Thereafter, prices tend to increase in real terms, due to a gradual increase in commodity prices. This increase, however, is offset partially by cross-subsidy reductions and lower costs to operate utility systems.

Natural gas commodity prices rose to high levels as a result of higher natural gas demand during the winter of 1996-97, and remained high during most of 1997. Additionally, while natural gas production capability was more than adequate to meet demand, the ability to get production into the pipeline in major supply regions has been restricted by the capacity to gather and process the gas for delivery into the pipeline. This condition resulted in less slack supply competing for market share, and therefore, sustaining higher prices during the past year.

Since November 1997, natural gas prices have fallen, primarily due to weather conditions being warmer than normal. In fact, the effects of El NiZo has reduced winter heating demand for natural gas in most regions of the United States, putting a downward pressure on natural gas prices. December 1997 commodity costs actually dropped by as much as a dollar per million Btu ($/mmBtu) to $2.25/mmBtu compared to the November 1997 price of $3.25/mmBtu. With a continuation of warmer than normal winter conditions, January 1998 commodity prices fell an additional 10 to 20 cents per mmBtu. Lower natural gas price trend should continue after the winter season due to a decreased amount of gas that will be needed to refill storage facilities for the next winter. Further, new supplies from offshore Gulf production region are expected to become available later this year. With lower demand to fill storage and more supply available, competition to sell gas could drive prices even lower.

After prices bottom out by the turn of the century, natural gas prices are expected to rise in real terms. Commodity costs will show small annual increases of about three cents per mmBtu. New technologies to explore, find, develop, and produce natural gas will help to keep the commodity prices from rising at a higher rate. Current CPUC policies to reduce end-use price subsidies and provide for more efficient utility operations will partially offset commodity price increases.

Figure 4
Base Case Comparisons
EG Gas Price by Utility Service Area



As Figure 4 indicates, natural gas prices to generate electricity in the PG&E and SoCal Gas service areas will be very competitive. This analysis indicates that commodity prices will be lower in the northern utility service area, but will have higher delivery costs than in the southern utility service area. This will produce very competitive prices for natural gas demand for electricity generation in both service areas. Detailed information for the various components that make up the electricity generation natural gas have not been included in this package, but are available on request or from the Commission's web-site, as noted earlier.

Due to additional costs to transport natural gas through the SoCal Gas service area, SDG&E natural gas prices for electricity generation are about 30 cents higher than that in the SoCal Gas service area. This trend will continue as long as the current pricing structure is maintained. The merger of the two utilities and unbundling of gas utility services could change this situation. This could possibly make the electricity generation sector price in SDG&E service area more comparable with prices in the SoCal Gas service area.

The proposed natural gas price forecasts are lower than previous Energy Commission forecasts. This is illustrated by Figures 5, 6 and 7, which compare natural gas prices for electricity generation over the past three adopted forecasts with the current base case. Historical prices are reported in recorded year dollars. Each of the forecasted prices are in nominal dollars, consistent with the inflation factors that were in use at that time. In each instance, the price trajectories have dropped due to changing market conditions and a better understanding of those conditions that drive natural gas prices.   This includes changes in the economy that affect inflation factors.

Figure 5
PG&E
Historical and Forecasted EG Gas Prices

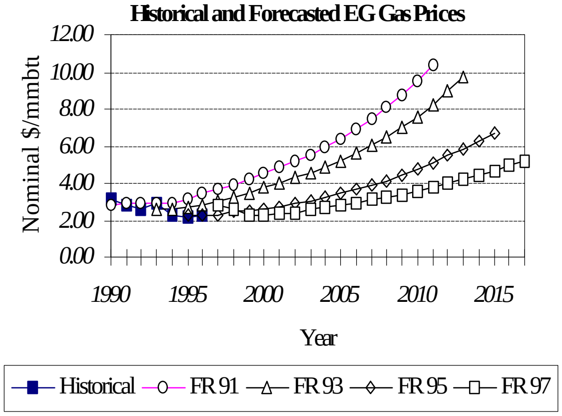


Figure 6
SoCal Gas
Historical and Forecasted EG Gas Prices

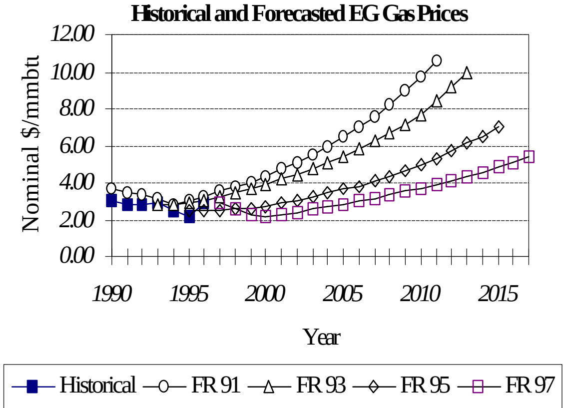


Figure 7
SDG&E
Historical and Forecasted EG Gas Prices

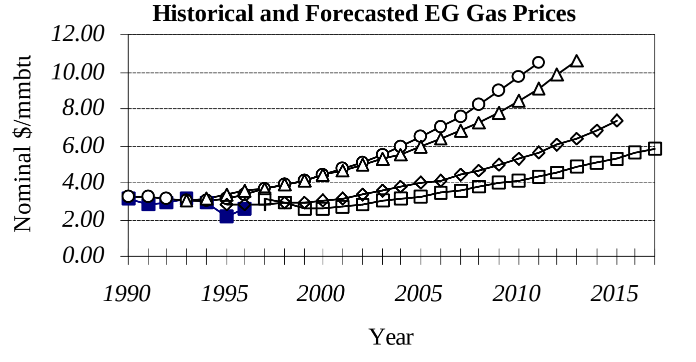


Table 4

PG&E

1997 Fuels Report

Committee Base Case

End-use Natural Gas Price Forecast by Sector

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1989	6.33	6.08	5.81	3.47	3.46	2.71	3.52	3.52	4.23
1990	6.42	6.33	5.59	3.63	3.94	2.93	3.65	3.65	4.40
1991	6.44	6.44	5.64	2.99	3.14	3.47	3.15	3.15	4.25
1992	6.20	6.77	5.04	2.89	2.31	2.72	2.87	2.87	4.51
1993	5.92	6.28	4.97	3.10	2.30	2.43	3.10	3.10	3.69
1994	6.11	6.32	4.65	3.02	2.06	2.05	2.32	2.32	3.62
1995	6.35	6.41	4.67	2.52	1.85	1.52	2.24	2.24	3.57
1996	6.74	6.77	4.68	2.99	2.32	2.05	2.36	2.36	4.07
1997	7.13	7.12	4.69	3.45	2.80	2.58	2.66	2.66	4.27
1998	6.78	7.32	4.22	3.46	2.46	2.38	2.41	2.41	4.00
1999	6.34	6.33	3.47	3.13	2.16	2.08	2.10	2.10	3.57
2000	6.09	6.08	3.42	3.01	2.05	1.98	1.99	1.99	3.36
2001	5.91	5.90	3.41	3.02	2.08	2.02	2.02	2.02	3.33
2002	5.73	5.72	3.41	3.03	2.10	2.06	2.05	2.05	3.28
2003	5.71	5.70	3.42	3.06	2.14	2.10	2.09	2.09	3.27
2004	5.70	5.69	3.43	3.07	2.18	2.13	2.12	2.12	3.30
2005	5.67	5.67	3.44	3.10	2.21	2.17	2.16	2.16	3.31
2006	5.63	5.63	3.44	3.13	2.24	2.20	2.19	2.19	3.27
2007	5.63	5.62	3.45	3.14	2.27	2.24	2.22	2.22	3.30
2008	5.58	5.57	3.45	3.15	2.30	2.27	2.25	2.25	3.29
2009	5.59	5.59	3.47	3.18	2.33	2.30	2.28	2.28	3.30
2010	5.59	5.59	3.49	3.21	2.37	2.34	2.31	2.31	3.33
2011	5.59	5.58	3.52	3.24	2.41	2.38	2.35	2.35	3.36
2012	5.56	5.56	3.53	3.28	2.46	2.43	2.40	2.40	3.37
2013	5.56	5.56	3.54	3.32	2.50	2.47	2.45	2.45	3.41
2014	5.56	5.56	3.56	3.36	2.55	2.52	2.49	2.49	3.44
2015	5.55	5.55	3.58	3.39	2.59	2.56	2.54	2.54	3.46
2016	5.57	5.57	3.61	3.43	2.63	2.60	2.58	2.58	3.49
2017	5.57	5.58	3.63	3.46	2.68	2.64	2.62	2.62	3.52

Note: * 1989 - 1995 prices are historical for residential, commercial, industrial, and TEOR; prices between 1995 and 1997 are interpolated.

* 1989 - 1996 prices are historical for cogeneration and UEG.

* 1997 and later years are forecasted.

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Table 5

SoCal Gas

1997 Fuels Report

Committee Base Case

End-use Natural Gas Price Forecast by Sector

1995 $ per mcf

		Core				Noncore			System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1989	6.62	6.11	6.11	4.96	4.63	3.07	4.08	4.08	4.99
1990	6.40	6.76	5.99	4.28	3.79	3.37	3.67	3.67	4.75
1991	6.99	7.34	7.34	3.91	3.64	2.86	3.22	3.22	4.72
1992	6.82	7.66	6.40	5.00	3.75	2.82	3.13	3.13	4.78
1993	7.24	7.65	6.71	4.98	3.73	3.16	3.14	3.14	5.01
1994	7.03	6.81	6.59	3.32	2.48	2.48	2.65	2.65	4.60
1995	6.69	6.55	5.85	2.39	2.29	2.01	2.26	2.26	4.26
1996	6.81	5.87	5.06	2.73	2.68	2.43	2.94	2.94	4.53
1997	6.93	5.19	4.26	3.07	3.06	2.85	2.87	2.87	4.42
1998	6.42	4.68	3.75	2.75	2.74	2.53	2.52	2.52	4.00
1999	6.02	4.30	3.38	2.39	2.39	2.22	2.13	2.13	3.60
2000	5.91	4.20	3.28	2.27	2.26	2.28	1.99	1.99	3.44
2001	5.90	4.21	3.30	2.31	2.31	2.33	2.04	2.04	3.45
2002	5.87	4.21	3.32	2.36	2.35	2.38	2.08	2.08	3.44
2003	5.91	4.24	3.36	2.41	2.41	2.43	2.14	2.14	3.50
2004	5.79	4.19	3.34	2.46	2.46	2.49	2.19	2.19	3.46
2005	5.84	4.22	3.37	2.51	2.51	2.53	2.24	2.24	3.53
2006	5.73	4.17	3.35	2.54	2.54	2.57	2.28	2.28	3.49
2007	5.71	4.17	3.36	2.59	2.58	2.62	2.33	2.33	3.52
2008	5.69	4.18	3.38	2.65	2.65	2.68	2.40	2.40	3.54
2009	5.79	4.25	3.44	2.70	2.70	2.73	2.44	2.44	3.59
2010	5.78	4.26	3.46	2.70	2.69	2.73	2.44	2.44	3.59
2011	5.76	4.27	3.49	2.75	2.74	2.78	2.49	2.49	3.60
2012	5.80	4.32	3.54	2.80	2.79	2.83	2.54	2.54	3.64
2013	5.80	4.34	3.57	2.84	2.84	2.87	2.59	2.59	3.66
2014	5.84	4.38	3.61	2.89	2.89	2.92	2.64	2.64	3.70
2015	5.84	4.40	3.64	2.93	2.93	2.96	2.68	2.68	3.72
2016	5.84	4.42	3.68	2.98	2.97	3.00	2.73	2.73	3.75
2017	5.86	4.45	3.71	3.02	3.01	3.04	2.77	2.77	3.78

Note: * 1989 - 1995 prices are historical for residential, commercial, industrial, and TEOR;
prices between 1995 and 1997 are interpolated.
* 1989 - 1996 prices are historical for cogeneration and UEG.
* 1997 and later years are forecasted.

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Table 6 - SDG&E

1997 Fuels Report

Committee Base Case

End-Use Natural Gas Price Forecast by Sector

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1989	6.74	6.68	6.68	4.57	4.57	0.00	4.05	4.05	5.17
1990	6.43	6.61	6.40	4.41	4.41	0.00	3.71	3.71	5.06
1991	6.05	6.13	6.13	3.88	3.88	0.00	3.25	3.25	4.61
1992	6.45	6.67	6.67	4.02	4.02	0.00	3.20	3.20	4.71
1993	6.85	6.87	6.44	3.81	3.96	0.00	3.33	3.33	4.97
1994	6.89	6.71	5.53	3.60	3.90	0.00	3.04	3.04	4.88
1995	6.44	6.32	5.31	2.71	2.74	0.00	2.18	2.18	4.01
1996	6.66	6.25	5.01	3.01	3.03	0.00	2.53	2.53	4.41
1997	6.88	6.18	4.72	3.32	3.32	0.00	3.07	3.07	4.56
1998	6.51	5.82	4.38	2.98	2.98	0.00	2.81	2.81	4.20
1999	6.23	5.54	4.08	2.62	2.62	0.00	2.41	2.41	3.94
2000	6.24	5.55	4.11	2.60	2.60	0.00	2.39	2.39	3.89
2001	6.29	5.60	4.16	2.64	2.64	0.00	2.43	2.43	3.94
2002	6.10	5.44	4.08	2.68	2.68	0.00	2.47	2.47	3.62
2003	6.17	5.51	4.14	2.73	2.73	0.00	2.50	2.50	3.73
2004	6.14	5.49	4.15	2.77	2.77	0.00	2.55	2.55	3.72
2005	6.15	5.51	4.18	2.80	2.80	0.00	2.59	2.58	3.78
2006	6.08	5.45	4.16	2.83	2.83	0.00	2.62	2.61	3.72
2007	6.04	5.42	4.16	2.86	2.86	0.00	2.65	2.65	3.70
2008	6.02	5.41	4.18	2.91	2.91	0.00	2.71	2.71	3.71
2009	6.03	5.42	4.20	2.94	2.94	0.00	2.74	2.74	3.78
2010	5.98	5.38	4.18	2.94	2.94	0.00	2.74	2.74	3.76
2011	5.95	5.36	4.19	2.98	2.98	0.00	2.79	2.79	3.76
2012	5.94	5.36	4.21	3.02	3.02	0.00	2.83	2.83	3.78
2013	5.93	5.36	4.23	3.06	3.06	0.00	2.88	2.87	3.79
2014	5.93	5.36	4.25	3.10	3.10	0.00	2.91	2.91	3.82
2015	5.93	5.37	4.27	3.13	3.13	0.00	2.95	2.95	3.86
2016	5.93	5.38	4.29	3.17	3.17	0.00	3.00	2.99	3.88
2017	5.92	5.37	4.31	3.21	3.21	0.00	3.03	3.03	3.90

Note: * 1989 - 1995 prices are historical for residential, commercial, industrial, and TEOR
obtained from QFER Form 7.
* 1989 - 1996 prices are historical prices for cogeneration and UEG
* 1997 and later prices are forecasted.

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